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A Summary of EPRI's Engineering and Economic Studies of Post Combustion Capture Retrofit Applied at Various North American Host Sites

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Abstract

With more than 300 GW of installed coal-fired plants in the US alone, and with many coal plants being currently built in China and India, it is conceivable that CO_2 will need to be removed from these existing coal-fired plant assets to significantly reduce green house gas emissions to acceptable levels. The Electric Power Research Institute (EPRI) recently completed a series of detailed economic and engineering studies examining the feasibility of retrofitting post combustion capture (PCC) to existing pulverized coal (PC) and/or circulating fluidized-bed (CFB) power plants, for five different North American "host" sites. Whilst studies have previously considered optimized retrofit on theoretical plants, the current work focused on retrofitting existing "real world" assets. This paper provides a number of performance and costs results from the extensive retrofit evaluation, as well as providing additional insight on the technical results and economic comparisons that emerged.

Keywords: Post Combustion Capture (PCC); Retrofit; Carbon Capture and Storage (CCS), pulverised coal; Circulating Fluidised bed (CFB).

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Introduction

Retrofitting PCC to an existing coal fired plant presents significant challenges.
Key issues envisioned include:

- Limited space for new plant equipment
- Limited heat available for optimized process integration - a result of no prior considerations for PCC in the original power plant design.
- Limitations of the existing steam turbine or the need to modify the steam turbine
- Cooling water limitations .i.e. the availability of water for increased usage arising from PCC plant
- Replacement power considerations
- Complicated pipe routings

With the intent to better understand these contributing factors and document and quantify their effect, EPRI undertook a series of detailed economic and engineering studies examining the feasibility of retrofitting PCC to PC and/or CFB power plants, for five different North American "host" sites.

As highlighted in Figure 1, the host plants considered are in a variety of locations with unique ambient conditions which directly influence thermal performance, and regional labor rates and productivity factors that influence installation costs.

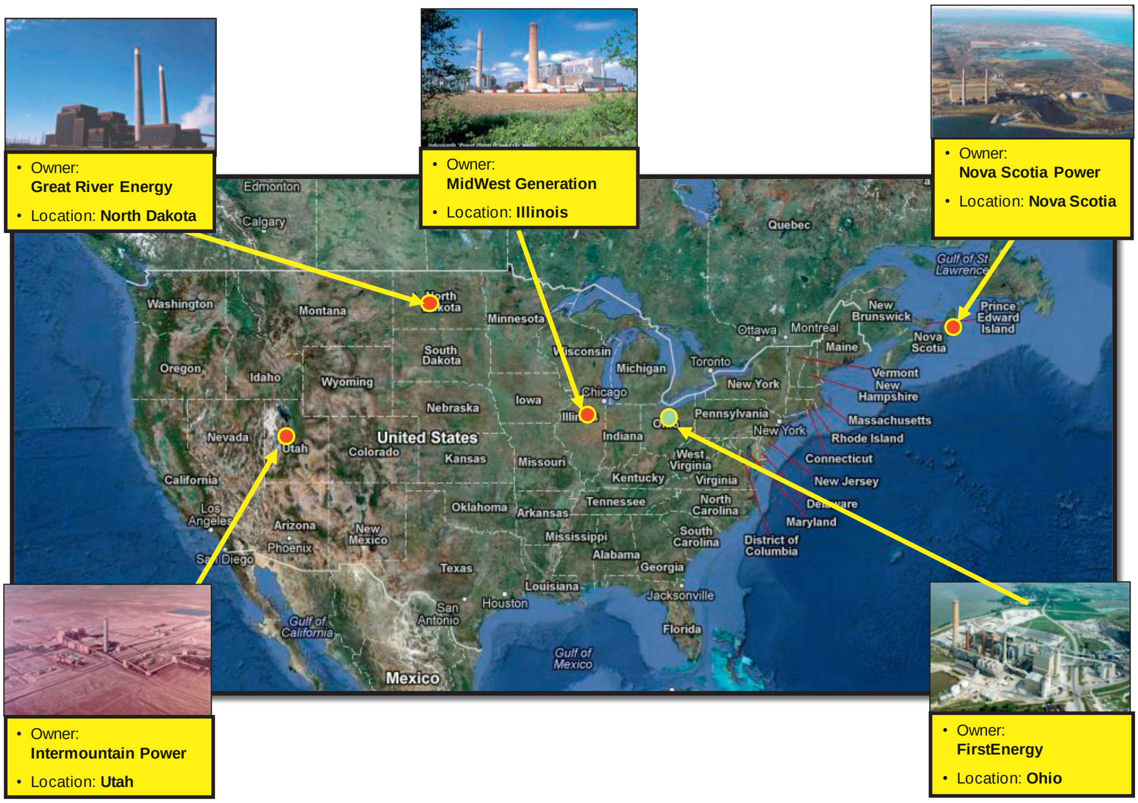

Figure 1. The North American locations of the five plants included in the EPRI study

Details of the five host sites selected for PCC retrofit are included in Table 1:

Table 1. Retrofit Host Sites

Plant Name	Bayshore	Lingan	Powerton	Coal Creek	Intermountain
Owners	First Energy	Nova Scotia power	Edison Mission (Midwest Generation)	Great River Energy	Intermountain Power Agency
Type	CFB	Subcritical PC	Subcritical PC	Subcritical PC	Subcritical PC
Fuel Type	Petcoke	Bituminous	Sub-bituminous	Lignite	Blend of Bituminous & Sub-bituminous
As received fuel Btu /lb (HHV)	13,350	10,958	8,700	7,045	11,010
Net Power Output (Prior to Capture)	1 x 129 MW	4 x 154 MW	2 x 750 MW	2 x 550 MW	2 x 900 MW
Location	Ohio, USA	Nova Scotia, Canada	Illinois, USA	North Dakota, USA	Utah, USA
Year Unit Built	2000	1979 - 84	1970 - 72	1979 - 1980	1987
De-SOx Equipment	Installed	None currently (Planned)	None currently (Planned)	Installed	Installed
De-NOx Equipment	None	None	None	None	None

To undertake this study EPRI assembled a retrofit team with engineering consultants Nexant Inc and architect engineers Bechtel Power Corporation. Nexant's expertise in process plant economic optimization was complemented with Bechtel's practical knowledge and experience in power plant design and construction.

Study Objectives and Approach

Each of the host sites offered a unique combination of unit sizes and ages, planned emissions controls, fuel types, steam conditions, boilers, turbines, and cooling systems. The data from these "real world" sites provided a broad insight into generalized cost and performance impact estimates for a variety of plant configurations.

Specifically the studies served to:

- Assess the most practical CO_2 capture efficiency configuration based on the existing site constraints
- Determine the space required for the CO_2 capture technology and the interfaces with the existing systems
- Estimate performance and costs for the PCC and compression plants
- Assess the features of each plant that materially affect the performance, cost and feasibility of the retrofit

Furthermore the support, participation, and level of engagement from the host utilities themselves culminated in five critical data points which are viewed as representative of the North American coal-fired power plant fleet.

Host-site engineers and performance specialists were available to support the data gathering and knowledge transfer activities required to establish base line performance prior to the addition of CO_2

capture. In addition, by providing vital operational knowledge and expertise these staff members ensured that the utility perspective was included in the PCC study.

The work is intended to allow utility stakeholders to gain an appreciation for full-scale retrofit requirements of today's amine absorption capture process and the issues associated with optimization and efficient integration to achieve 90% CO_2 capture on an existing coal power plant asset.

By incorporating the plant-owners perspective this approach identifies features of plant design and operation that may result in additional complexity and/or cost when retrofitting PCC. This unique insight is intended to assist other generators in determining plants within their own portfolio that are the best candidates for potential future PCC.

As a direct result of site host's active participation and diligence, knowledge has been collated in several critical areas including the effect of fuel feedstock used, plant operational requirements for turn-down, permitting implications, water consumption, required Air Quality Control System (AQCS) upgrades and in optimizing feed water integration to minimize parasitic power loss and reduce cooling water consumption. Within this particular paper, the aim has been to benchmark the economic and efficiency impacts associated with full integration of 90% CO_2 capture to a representative sample of the current North American generating fleet. Such accurate and impartial, information should be invaluable to policy makers in establishing the most economic approach to achieving a future low-carbon economy

Performance comparison results

Figure 2 below shows the plant performance for all five sites studied, both before and after retrofit was applied. The diamond values correspond to the net plant efficiency on the right axis, the column values correspond to the net/gross power output on the left axis. In addition, a new build USC PC1100°F (593°C) is also shown to compare the results from older PC unit retrofits with a new PC unit retrofit.

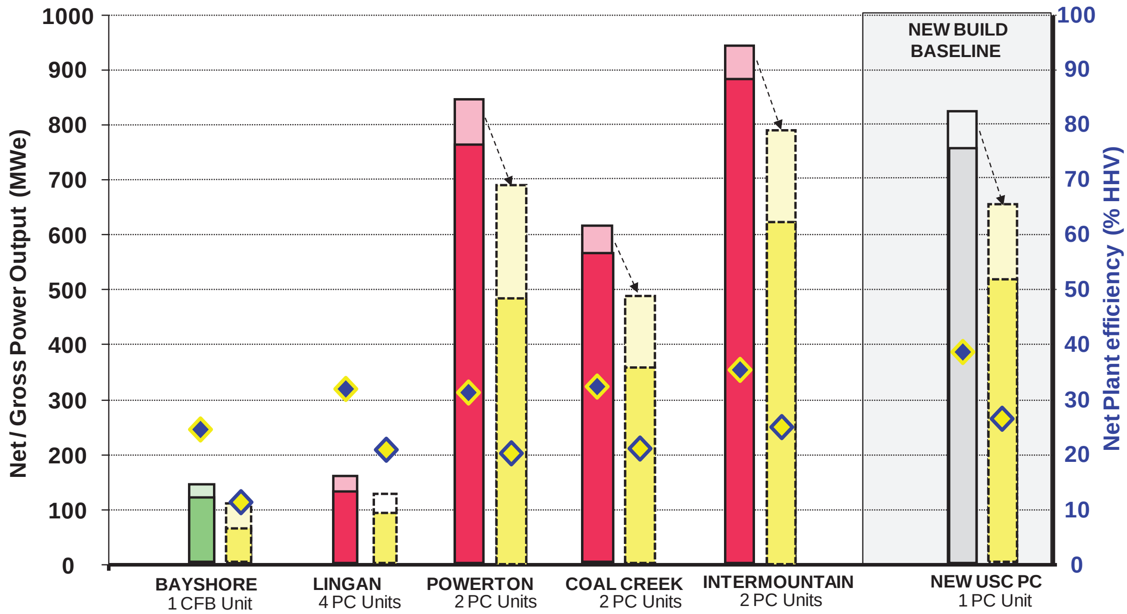

Figure 2. Plant performance before and after retrofit. Solid diamonds represent net plant efficiency before retrofit and open diamonds represent efficiency after retrofit. The heavy-shaded portion of the bars represents net plant power, and the light-shaded portion represents the auxiliary or own-use power.

The Bayshore station unit is a petcoke fired CFB that supplies a portion of its process steam to a nearby refinery. (Note that this initial loss of direct generation power as a result of the exported steam agreement is the reason for the low net plant efficiency). The Lingan Station consists of four small boilers each with their own steam turbine that will share two planned FGD's. The Powerton Station features four boilers with two steam turbines (two units) with four planned FGD's. The Coal Creek Station features two lignite boilers with their own steam turbines as well as FGD's and state-of-the-art coal drying equipment (DryFining^{TM}). The Intermountain Station consists of two boilers with their own steam turbines and FGD's. The 1100°F series USC baseline plant has the highest efficiency. This single unit with its state of the art AQCS system in place, is as defined in previously published EPRI PCC studies[(1)], is fired with (8340 btu/lb HHV) PRB coal and assumed to be sited in Kenosha, Wisconsin, USA.

All units examined have the same advanced amine CO_2 capture technology and deliver the final CO_2 to the same specification and compression level. The final calculated net efficiency penalties associated with adding capture, compression and storage ranged between 14 and 11% percentage points and are shown for each site in Table 2. Note that whilst having a higher baseline efficiency prior to capture was found to be a good indicator, this does not necessarily mean that the capture efficiency penalty was the lowest after retrofit was added, Other influencing factors are therefore present, as highlighted in the conclusion section of this paper. For example in comparing Intermountain with the new USC case, while having a higher overall plant efficiency prior to PCC, the capture penalty for the USC case is larger at 12.2%. This is believed to be influenced by (a) the USC's use of a lower HHV coal feedstock and (b) certain inherent design features of the existing USC steam turbine design, such as the IP /LP crossover pressure and the LP turbines efficient response to turndown.

Table 2. Calculated capture penalty

	Bayshore	**Lingan**	**Powerton**	**Coal Creek**	**Intermountain**	**USC**
Net efficiency penalty from adding capture	14.0% points	12.0% points	11.6 % points	12.0% points	11.0% points	12.2% points

Economic comparison

Figure 3 shows the Total Plant Cost (TPC) comparison (Inputs defined in appendix A) for the retrofits, against a new build PC with capture. If one assumes the existing plant is a fully paid off asset, then Figure 3 shows that there is a significant difference in upfront capital investment associated with adding CCS compared to new build. Note: Lowering initial capital investment could be a strategy adopted to significantly lower the risks associated with first generation CCS technology deployment.

Figure 3 shows that retrofitting PCC to a paid off PC plant can lower the capital investment significantly compared to an entire new build with capture. TPC for the new build is \$4200/kW and as low as \$900/kW for the Intermountain retrofit, a difference of \$3300/kW. However, whilst retrofitting PCC to an existing paid off plant clearly requires much less investment than building a new PC with PCC, it was found that the incremental cost of adding the PCC can be more for an existing plant than a new plant depending on its own unique circumstances. In the case of the Bayshore CFB Unit, it can clearly be seen that the additional investment required to add CCS, combined with the low level of overall MW generated (a direct result of the refinery export steam commitment) resulted in a very high \$/kW level for retrofit.

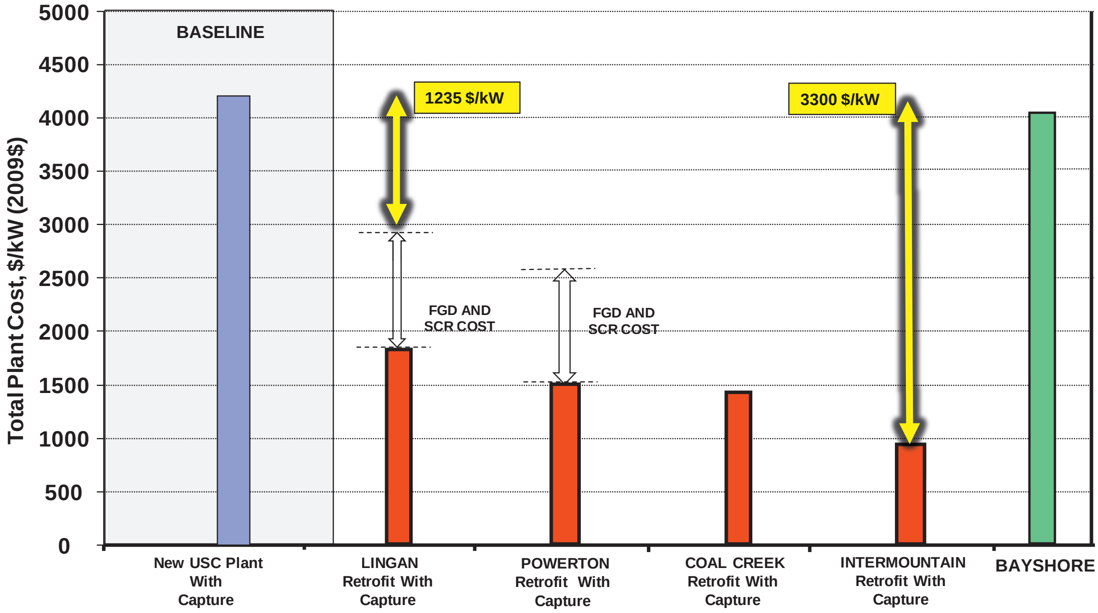

Figure 3. Capital cost comparison of retrofit versus new build for the PC units. Note: grey baseline boxes are not the actual site LCOE values, they are EPRI estimates of the baseline LCOE, based on assumed fuel and operation costs which are then applied consistently after capture. (See appendix A for assumptions)

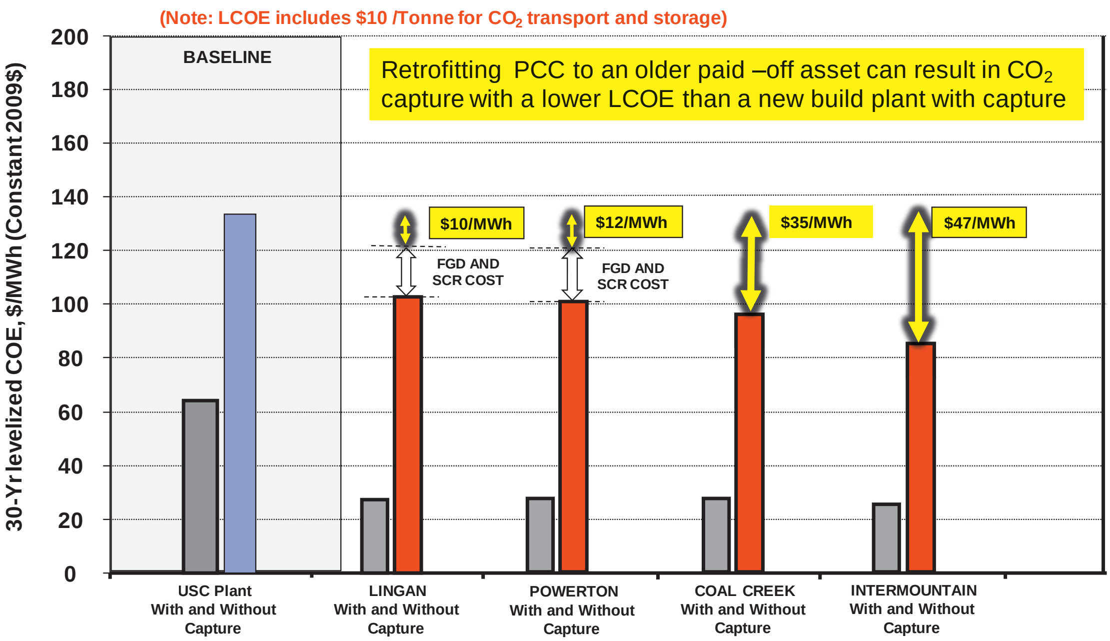

Figure 4. LCOE comparison of units with and without 90% CO_2 capture (See appendix A for assumptions)

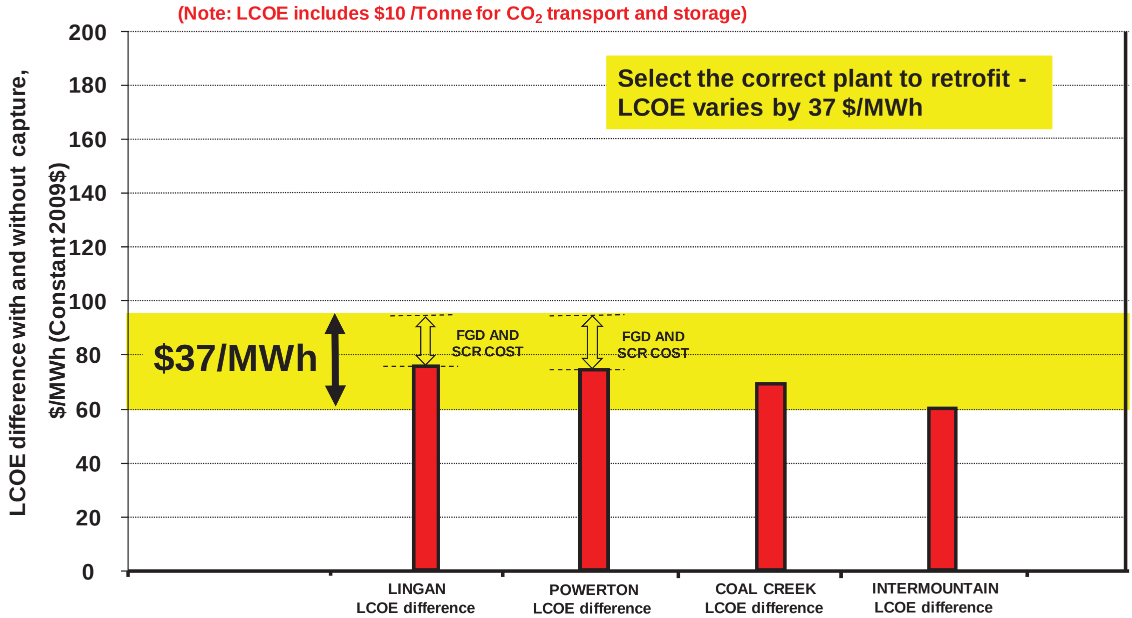

Figure 5. Variance between each site of the LCOE penalty associated with adding capture (See appendix A for assumptions)

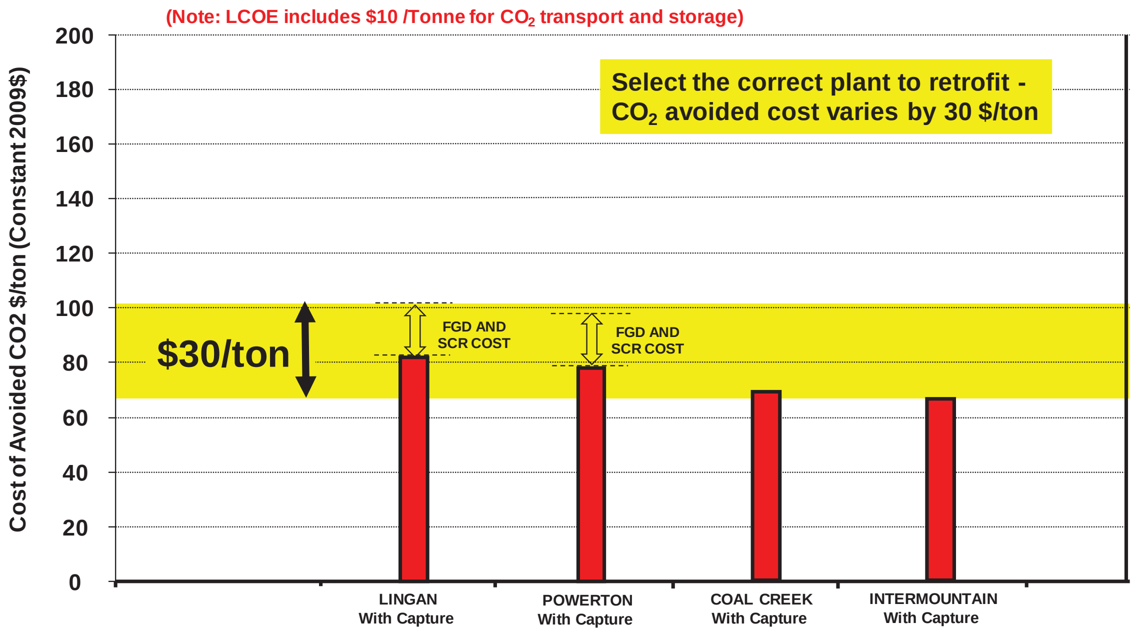

Figure 6. Variance between each site of the Cost of avoided CO_2 (See Appendix A for Assumptions)

Bayshore CFB case aside, Figure 4 shows the LCOE comparison for the PC units with and without capture. Again, assuming all the retrofit PC plants are paid off assets and will continue to operate for another 30 years, then retrofitting PCC can result in a lower LCOE compared to a new build with capture, somewhere between \$10 to \$47/MWhr compared with a new build plant. (LCOE for the new build is \$132/MWh and as low as \$85/MWh for the Intermountain retrofit, a difference of \$47/MWh).

Figure 5 shows the range of the LCOE penalties for the PC retrofits to be \$37/MWh.

Figure 6 shows the range of CO_2 avoided costs for the PC retrofits to be \$30/ton – Note: adding AQCS equipment is seen to make up half of this difference for both LCOE and CO_2 avoided comparisons.

Further improvements

The study also considered the improvements in retrofit performance gained by using more advanced PCC solvents with lower heat of regeneration, the likes of which are currently being developed by technology suppliers. For the Intermountain case a 2.5 percentage point improvement was achieved as shown in Table 3.

Table 3. Estimated Performance of Intermountain with advanced solvent Process

		Intermountain Plant	
Plant	**No Capture**	**Retrofit With Current CCS**	**Retrofit With Advanced CCS**
Heat of Regeneration btu/lb CO_2 (kJ/kg)		1380 (3210)	900 (2093)
Gross Output (MW)	947	798	848
Aux Load (MW)	50	178	178
Net Output (MW)	897	620	670
Drop in net output from Baseline (MW)		278	227
Loss in efficiency percentage points		- 11%	-8.5%

Conclusions:

- Despite the clear differences in base plants selected, all the sites studied were shown to be technically capable of being retrofitted with today's PCC technology at the 90% level of capture.
  - No technical showstoppers were found with the currently available technology
  - The extremely low initial efficiency of the Bayshore unit makes it an unattractive capture option. This is however not a reflection on CFB technology with capture but rather due to the plants existing export steam commitments
- Assuming the existing plant is fully paid off and that it could operate for another 30 years, adding PCC would result in a lower LCOE than that from a new USC with PCC.
- Not all the PC retrofits are the same:
  - The capital investment required differed by approximately 2000/kW, with much of the difference occurring because two of the plants had to add FGD units
  - The resulting LCOE differed by approximately \$37/MWh
  - CO_2 avoided cost differed by approximately \$30/ton
  - Of the plants studied, from a capture perspective, Intermountain is recognized as the best option (See Table 4 below)
- Future solvent improvements have a significant part to play in lowering the current estimated CCS efficiency penalty for retrofits
- Using the advanced solvents, currently under development was seen to lower the generating efficiency reduction by 2.5 percentage points, and further improvements are likely. Improving efficiency also lowers capital and operating costs resulting in lower COE and avoided cost of CO_2 capture

Table 4. Intermountain Characteristics

Key contributing features to Intermountain's suitability for PCC retrofit:	
Good baseline efficiency (Net plant efficiency 35.6%)	High heating value of the combustion fuel
Reasonable IP / LP crossover pressure for steam supply to PCC	Favorable construction / labor costs
Existing AQCS FGD system with potential upgrade	Size – 2 x 900 MWe Gross (Good economies of scale)
Space available for PCC equipment in the right areas	Base loaded operation
Age – Commissioned 1987 (24 years old)	Existing stack can be utilized

Acknowledgements

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Appendix A:

Key economic assumptions included in this study:	
No contingency applied to PCC equipment	90% capacity factor applied
Coal price:	All capital costs have been adjusted to 2009 dollars
PRB $1.80/MMBtu (HHV), $30/ton as-received. (17% price increase added for Bituminous & blend)	For retrofits assumed paid off base plant
Costs estimate were based on a +/- 30% accuracy from pre-front-end engineering and design studies	12.5 % annual capital carrying charge factor applied
LCOE based on investor-owned utility revenue requirement analysis	Captured CO_2 is compressed to 2205 psig (152 barg)
Optimized 30% wt. MEA system used on all cases (1380 Btu/lb-CO_2 Heat of Regeneration)	
Constant value of $9.1/ton ($10/tonne) was applied to account for transport and storage.	
The TPC used, is defined as the sum of the following: Capital cost (broken into materials and installation including labor, subcontracts, field indirect costs, no sales tax assumed) / Engineering and other Home Office Overhead, including Fee / Warranty costs / Any Contingencies applied.	